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Financial appraisal of operational offshore wind energy projects

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ABSTRACT

This paper investigates the commercial attractiveness of the nascent offshore wind energy industry from an asset owner's perspective. Two commercial scale operational projects are used as illustrative cases. Based upon historical empirical financial and performance data in conjunction with future spot market price scenarios, a discounted cash flow methodology has been applied to underpin the financial value over each life cycle of plant. The robustness of the results is strengthened by sensitizing key input parameters. The results suggest that project annualized returns range between 8% and 11% above prescribed costs of capital. A key finding is that the cost of capital can be more instrumental in achieving lower costs of energy than site selection itself.

Contents

1. Introduction

Currently a paradox exists within the offshore wind energy landscape whereas both development activity and capital costs have been growing simultaneously industry wide. Industry wide stakeholders aspire to see the overall costs of offshore wind energy decline as a result of combining technological learning experience in manufacturing and installation gains, economies of scale, entrance of new market participants intensifying competition, and more efficient industry practices, but historic empirical evidence suggests the opposite has been occurring. Many studies pertaining to market development in offshore wind energy have either focused on either subsidy support framework mechanisms or capital cost structural factors. However little attention has been given in the academic field as to what profitability is when pursuing the deployment of offshore wind. Therefore it is worthy of intensive investigation to seek to understand what the financial merits of offshore wind energy are based upon the analysis of empirical evidence from some of the first commercial scale project sites.

The research objective of this paper is to investigate the financial merits of two specific pioneering projects in the United Kingdom's offshore wind market. This paper argues that by tracing the evolution of financial viability of commercial scale offshore wind energy projects, we can attempt to understand commercial motivations for pursuing this particular emerging energy technology. Detailed project descriptions also delineate some of the technical challenges that arose during the first few years of both projects' operations. The sensitivity analysis on the results depicts

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key parameters that affect economic viability. Amongst these sensitivities, future electricity price scenarios demonstrate how changes in the macroeconomic environment affect renewable energy generators' profitability within the UK. The results indicate that in these early developments positive returns were made possible through both up front and production tied subsidy support.

The paper is structured as follows. First a backdrop of the offshore wind industry evolution is presented. Next the methodology is presented followed by describing data collection and analysis. Operational and financial performance is then assessed, concluding with a discussion about the results.

2. Offshore wind energy evolution

In response to a 1997 White Paper concerning a strategic action plan for renewable energy expansion and the corresponding EU Directive that followed in 2001 [1,2], EU member states sought out to explore their renewable resource potential on a national basis. Many countries across the EU chose to pursue wind energy as a commercially scalable renewable energy resource option, partially attributed to its growing maturity and economic positioning. In 1997 when the White Paper was published, only 4 753 MW of wind energy had been installed across the EU [3]. However by the end of 2009, 74 767 MW of cumulative wind capacity had been installed, reflecting an annual cumulative growth rate of 27.2% [3]. The lion's share of this growth was incurred with traditional land based installations. Due to the high population density per square kilometer within the EU, locating and securing new favorable sites has become more troublesome for developers within the past five years. Some specific roadblocks developers had identified for pursuing more on-land development included: social objections (NIMBY affairs), lack of spatial availability, insufficient wind resources at remaining sites, and on-going siting and construction permitting risks. This culmination of factors created an interesting development for the wind energy business whereas developers have been shifting their attention offshore where more favorable wind regimes and spatial availability exists. In the late 1990s and early 2000s, a new subsector of wind energy was born in Denmark when wind turbine generators (WTG) were deployed in the seascape environment.

The world's first offshore wind farm, *Vindeby* at 4.95 MW capacity, was built off the Danish coast in 1991 [4]. A decade later in 2001 the first commercial scale[1] offshore wind energy plant *Middlegrunden* came online [5]. At the time socio-economic research focused on the market potential for future activity, which offered promising commercial findings [6,7]. Shortly thereafter in 2001–2002 the size and scale of Danish commercial scale offshore wind parks took a massive leap with the 160 MW *Horns Rev* installment followed by the 165 MW *Nysted* project [8].

Per contra to Denmark where offshore wind experiences were initially politically driven, the advances within the UK were industry led. The public attitudes towards onshore wind energy lie at opposite ends of the continuum in the UK and Denmark. Whilst Denmark has a long and well documented history of onshore wind utilization, the UK simply did not. Wind energy project developers in the UK faced continued social objection to onshore wind energy projects, as many projects were held up in planning hearings and opposition social campaigns resulting in either project delay or outright license application denial.

In December of 2000 the UK's Crown Estate (landlords of the sea up to 12 nautical miles from shore) announced what was called Round 1, the first round of offshore wind farm development permitted in UK waters [9]. The original intent of Round 1 was to gauge the interest private energy developers had in erecting WTGs in UK's oceanic waters [10]. According to the IEA, the UK government approach was not to directly "promote" any specific technology but rather it sought to provide the framework for development, so that a technology which is ready to be exploited, could be [11]. Of all the developer solicitations, seventeen companies were ultimately awarded site development entitlements [9]. The Crown Estate specifically asserted "Round 1" was intended to act as a 'demonstration' round providing prospective developers with an environment in which they could gain technological, economic and environmental experience [9]. In the IEA's opinion, the overwhelming industry response to Round 1 was both surprising, and a major signal to government of the potential for offshore wind [11]. The UKERC concluded in 2010 that at the time of Round 1, aspirations to move offshore were fueled, in significant measure, by the problems associated with securing planning permission for onshore wind farms [12]. Whilst the original intent of Round 1 in the year 2000 was to gauge the interest private energy developers had in erecting wind turbines in UK's oceanic waters [10], the net result was an overwhelming industry response exposing the UK's immediate need for subsequent government backing to pursue the development of the industry [13]. The positive developer response to the Round 1 licensing phase resulted in a February 2002 Energy White Paper containing the UK government's first explicit and positive backing for the importance of offshore wind [11].

Renewable energy has always been a politically fickle topic, and the advent of offshore wind energy has also been viewed as a potential strategy to meet multi-fold objectives of meeting required EC carbon reduction targets while simultaneously maintaining political favorability. By appeasing the wishes of constituents by siting such energy projects out of close visual proximity, the end result to political leadership is increasing the probability of re-election. According to the UK's Department of Energy and Climate Change (DECC), the motivation to pursue this market segment was clear. It was seen as part of long-term low carbon energy mix, it offered diversity of fuel sources and reduction in dependence on fossil fuel imports, and the sector offers prospects of business and employment benefits, to the tune of up to half a million jobs generated in the entire UK renewables sector and its supply chains valued at £100 billion worth of investment opportunities [14]. Selling the higher cost of renewable energy under the auspices of jobs creation has been refuted, as the Oxford Institute for Energy Studies (2003) stated that 'constructing offshore wind generation capacity will not provide significant numbers of new UK jobs but merely creates a less optimal allocation of labor by distorting the labor market through the subsidization of unnecessary offshore wind parks' [15].

For the commercial actor stakeholder group, factors promoting the first move into offshore wind included experiencing "mild pressure" from government to fulfill carbon reduction targets; responding to positive policy and market signals; a developer's own association with the coastal or the offshore engineering sector and a strong desire to develop a new market based opportunity [11]. There was a strong sense amongst the developer community that offshore wind could be the next industry trend and shift, although little experience had been gained in the pre-2005 period. Amongst commercial actors, there was a sense that players did not want to be left behind for the next promising technology, which was already proving a reality in Denmark in the early 2000s [11].

These advancements sent a ripple wave of excitement through industry actors such as corporate utilities and turbine manufacturers. The forefront of commercialization for a new market opportunity, first originally only envisaged, was beginning to be seen. This resulted in select actors choosing to implement a first

[1] Commercial scale being defined as greater than 25 MW.

mover strategy with intent to secure preliminary competitive advantages within technology construction processes. Such pioneering activities can be viewed as 'vanguard projects' whereas these first of a kind projects enable firms attempt to diversify operations into new technologies or under established markets by testing potential opportunities [16]. In the case of offshore wind, investment that builds knowledge or beneficial organizational, technological, or market information may also have additional strategic value that will feed into the investment decision [17]. During this time there was a lack of empirical evidence or common knowledge to base investment decisions upon, leaving many to speculate about future market potential. It was said [12] that as was possibly the case for offshore wind, many developers of new technologies commonly exhibit 'appraisal optimism', whereby in the absence of data derived from commercial experience the costs of a new development are underestimated and returns exaggerated.

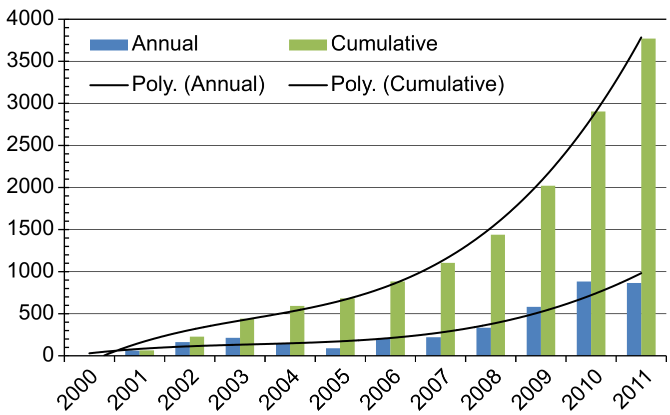

Fig. 1. Offshore wind energy capacity (MW) installation growth 2000–2011 [19–22].

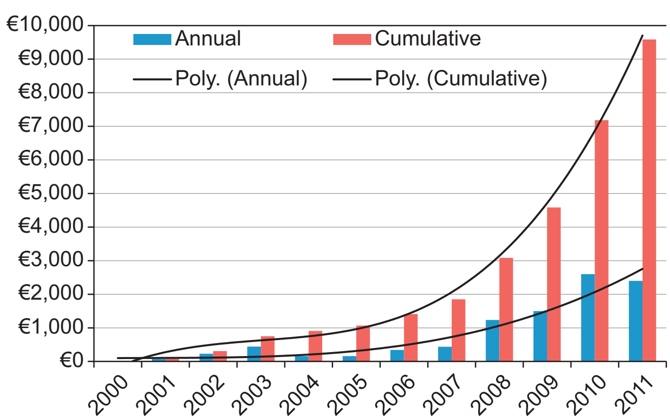

Fig. 2. Annual offshore wind energy investment volume 2000–2011 (million €) [18,21–23].

The rise of the infant industry from its initial nascent stages to its current scaling up can be visualized in Figs. 1 and 2. Whilst the market only received investment volume of €71 million in 2001 [18], it saw turnover in 2010 of approximately €2,6 billion [19]. As visualized in Figs. 1–3, the market is tipping onto the verge of expansion into a full market economy in the forthcoming 10 years.

The benefits of offshore wind energy have been widely published. In summary, offshore wind speeds are more robust and consistent, there is less social opposition corresponding to less risk in obtaining concessions, and there is a greater ability to scale up the size of each parks installed capacity (through quantity and size of turbines). Enterprise motivations behind pursuing the sector include (in order of importance from surveys in 2007 and 2010): strategic opportunities, exploration of future markets, green image, high expected returns, and reactive actions towards competitors [25]. From the regulatory standpoint, the motivation for promoting and supporting offshore wind has been deeply rooted in finding scalable solutions to meet carbon reduction targets under the EU 2020 Renewable Directive. In 2009, the EU set out a directive that mandated the UK derive 15% of its energy consumption from renewable resources by the year 2020, as compared to 1.5% in 2005 [26]. In order to meet this directive a total of 91 TWh of electricity must be generated through offshore wind resources, the equivalent of 29 GW of installed capacity [27]. Other justifications include securing domestic energy supply (reducing dependence on fossil fuel imports) in addition to pursuing domestic business and employment benefits. For deeper understanding of offshore wind energy motivation from the commercial paradigm see [28–30] or see [11,31] for political motivation.

Other social science research has followed a wide range of topics in pursuit of understanding exemplified non-technical barriers to widespread deployment. These paths include studies on permitting policy and spatial planning, public perceptions, and the NIMBY affair [32–35]. Numerous other studies have focused on the disparate national subsidy support political framework mechanisms of energy policy (tradable mechanisms, feed in

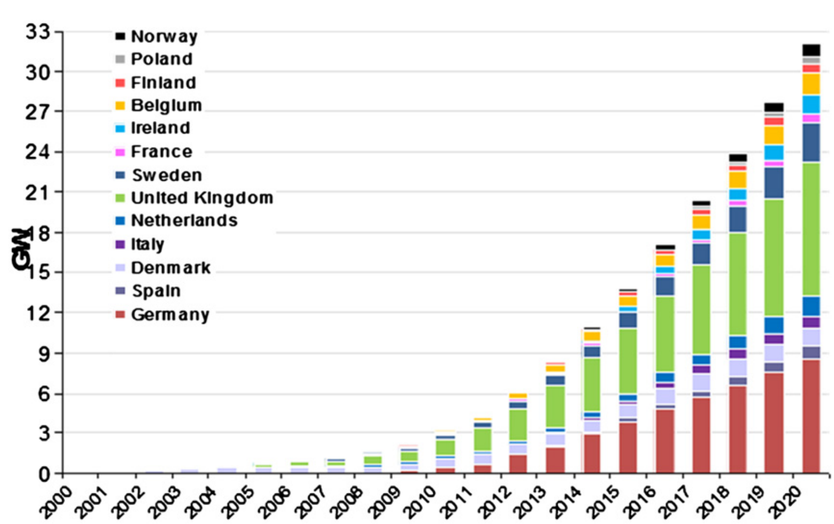

Fig. 3. Offshore wind energy capacity installations and forecasted cumulative growth 2000–2020 [24].

tariffs, tax credits, etc.). Whilst several prior authors [31,36,37] had narrowed their focus on the UK's renewable energy financial subsidy framework, Green & Vasilakos [38] are the only authors who have assessed diverging European national subsidy frameworks specifically for the offshore wind industry. Recently in 2009 research was presented [39] showing how the change in wind power ownership structures towards large capitalization corporate entities is shaping the future of the wind power industry within Europe.

However, little academic research has been devoted to the commercial aspects directly affecting the offshore wind industry, namely underlying profitability for principal asset owners. Whist Snyder & Kaiser [23] did offer a cost benefit analysis of environmental and economic tradeoffs, nearly all offshore wind energy economic academic publications can be grouped into either cost or benefit themes. Numerous commercial consultancy publications have filled parts of this void, perhaps best explained by their unique deep-rooted working relationships with active industry actors. The most common financial metric discussed is capital expenditure, simply defined as 'turnkey investment costs for delivering operation of plant.' The evolution of rising capital expenditure (CapEx) of offshore wind deployments over time has been well documented in various publications, and was quite arguably dissected most comprehensively by Garrad Hassan [40] and the United Kingdom Energy Research Centre (UKERC) in 2010 [12].

Many publications [4,11,12,27,28,30,40–45] have applied various learning or experience curves, economies of scale or other such cost reduction methodologies to forecast the changing nature of future capital expenditure per installed MW within the sector. However for numerous widely cited factors such as crimped supply chain and the lack of dedicated turbine suppliers[2], unfavorable exchange rates, shortage of installation vessels, and the general trend of moving further and deeper offshore (two moves that obviously result in higher expenditure), all estimations have under-projected the costs realized for project developers. In 2010 UKERC [12] concluded that learning curves were prematurely applied at an unrepresentative stage to the offshore wind sector. This conclusion supports the ideology that in order for the industry to achieve such cost reductions through learning curves, a consistent and steady stream of component procurement, construction, and operation activity must take place within the same group of actors with some degree of open information exchange to facilitate such cost reductions.

The inherent paradox that exists within the offshore wind energy sector is the simultaneous swelling of both capital expenditure and ensuing deployment activity. In order to better understand this current paradox, this paper argues a historical approach must be undertaken in attempts to underpin the commercial value of engaging in project activity from the developer's perspective.

3. Project specific features

Two operational projects were selected to analyze as illustrative cases. Both offshore wind energy projects were built in UK waters within a two year time span, however their opposing national geographic locale offers insight as to how profitability can be affected through site selection.

The North Hoyle project off the coast of Wales was the first commercial scale UK offshore wind farm built in 2003. The 60 MW project is comprised of 30 Vestas V80 2.0 MW WTGs each supported on a tubular steel monopile foundation. The hub height of each WTG is 70 m above lowest astronomical tide [46] in a water depth of five to twelve meters approximately eight kilometers from the shore [42]. The total finalized project cost amounted to £81 million [47]. The project was awarded a £10 million capital grant from the UK government, and received a £2.2 million demonstration grant from the European Commission [48]. Therefore the developers realized CapEx equated to cost per installed MW of £1.146 million. For juxtaposition, current megawatt-weighted estimated capital costs for projects at or near financial close in January 2009 was £3.2 million per MW [49].

Scroby Sands in East England utilized the same quantify and size of WTGs from the same manufacturer as North Hoyle. A turnkey contract for procurement of plant (EPC) was entered in 2003, with commercial operation commencing in December 2004. It was constructed 2.5 km from shore on a large sand bank with water depths of 2–10 m with a tidal range of 3 m [8]. Although total upfront project cost was £75.543 million, E.ON reduced their capital exposure by 13.2% through the £10 million capital grant from the UK Government [50], bringing CapEx down to £1.092 million per installed MW.

4. Methodology

Offshore wind energy economic literature has focused on three primary metrics: capital expenditure, operations and maintenance expenditures, and levelized cost of energy (LCOE). By projecting costs of generation on a per unit basis (£/MWh), the LCOE work has been conducted to inform investors and regulators [12,49,51] or in order to assess financial competitiveness between technologies commonly competing for the same pool of subsidies [49,51–55]. The latter explaining how this metric is utilized as a tool to shape the political context by enabling regulators to assess the levels of subsidy support offered. Whilst CapEx, OpEx and LCOE are key components of the economic balance, they only elude to half of the financial equation in the commercial paradigm.

As displayed in Fig. 4 the methodological process of financial appraisal applied here incorporates present values of future benefits and costs thus underpinning the financial merit of a project and deriving the impact upon the proprietor who undertakes the risk associated with it. Applied financial appraisal utilizes conventional discounted cash flow methodology (DCF) whereas the discounting process allows diverging cost and revenue streams with different time-shapes to be properly compared. Data was collected and analyzed based around two existing offshore wind parks in the UK. The objective of applying this methodology is simply to assess offshore wind's capacity to produce financial returns on an individual investment project basis.

A research boundary was drawn to clearly define the immediate tangible financial merits of two operational offshore wind parks excluding esoteric and often debatable social or environmental

$$NPV = \sum_{n=1}^{N} \frac{[(Ps + LECs + ROCv) - (OpEx + Dx)]^{n}}{(1+r)^{n}} - CapEx$$

NPV = *Net Present Value*
N = *Sum of periods (267)*
n = *period in monthly time series*
Ps = *Power sales*
LECs = *Levy Exemption Certificate sales*
ROCv = *Renewable Obligation Credit values*
OpEx = *Operational Expenditures*
Dx = *Decommissioning costs*
r = *Discount rate*
CapEx = *Capital Expenditure*

Fig. 4. Financial appraisal methodology.

[2] Attributed to the global rise of on-shore wind turbine generator demand.

metrics. This issue clearly reflects the fact that many of the benefits of renewable energy are difficult to monetize, and therefore are ignored when investors make decisions on new electricity plants from a purely financial viewpoint. However it cannot be ignored that corporate strategy may dictate undertaking the pursuit of such risky renewable energy technologies, under the namesake of 'greening' existing generation portfolios to project an environmental corporate image.

5. Data collection & analysis

Performing financial appraisal demands acquisition of revenue and expense figures. Key data required for expense accounts included capital expenditure (CapEx), and ongoing operations and maintenance expenditure (OpEx). Key data to derive income accounts includes production in megawatt hours (MWh), historical wholesale electricity market prices, Renewable Obligation Credit (ROC) values, and Levy Exemption Certificate (LEC) values. Analysis was required within all aforementioned accounts to either collate time series to a common denominator or model figures into the future. Missing data was future decommissioning costs, in which was adopted from Offshore Design Engineering's forecasted figure of £8.25million per project (£275,000 per WTG) [44].

CapEx and OpEx data was acquired from three years of UK Business Enterprise and Regulatory Reform (BERR) operational reports that were prepared and submitted by the project developers in consideration for the £10 million capital grants provided [47,50,56–59]. Production data was extrapolated from the UK's utility regulator Office of Gas and Electricity Markets (Ofgem) [60]. Ofgem tracks ROC distributions per approved renewable energy generating station; this source was also utilized to quantify the LECs generated.

Due to the lack of long term (post 10 years) operational data, there is no empirical evidence to cite long-term offshore OpEx. Even within the 10 years time frame, actual figures are under debate. Peter Asmus framed this issue most succinctly when stating *"this is an industry in transition, operating within an incredible vacuum of knowledge about operations and maintenance costs"* [61]. Table 1 synthesizes various assessments made across the industry, which reflects that there is no industry wide accepted common framework for which to calculate OpEx. By applying other researchers' values to the North Hoyle project, a solution of clear and transparent harmonized figures is offered, thus solving the incongruent approach conundrum. Figures in black are the original value from the cited source. Figures in italics have been calculated as a basis for comparison to synthesize values from different methodologies. The North Hoyle CapEx of £81 million and five year average annual production result of 184 GWh has been used as a basis of calculation to produce the results.

While the long term OpEx debate continues to go on, decisions must be made today about how to model these costs to create an equitable and realistic representation of the life cycle costs of operating and maintaining an offshore wind farm. For the basis of the financial and economic analyses carried out within this study, an assumption is made that OpEx will continue to rise in cost from its last reported annual figure to a maximum cost of 5% of CapEx per annum, exclusive of decommissioning costs. Whilst this assumption is mostly supported by the aforementioned literature review, it is recognized that these values assigned carry a degree of uncertainty. It is believed this choice of values is supported on the basis that as each WTG grows older in its life expectancy, it should be expected to incur larger proportions of component failure, thus requiring more time and resources allocated to maintaining the asset. Occurs after year three. The annual increase in cost will be linear for 15 years, increasing at the differential rate between its maximum of 5% of CapEx and the last recorded figure of OpEx, expressed in the same terms.

The main pillar of the current renewable energy policy framework is the Renewables Obligation (RO), which places a requirement on UK electricity suppliers to source a growing percentage of electricity from eligible renewable generation sources. In order to meet their obligation, energy suppliers must prove to Ofgem they have purchased energy from renewable sources by presenting Renewable Obligation Certificates (ROCs), or alternatively, by making a fixed financial payment (a buyout price), or some combination of the two. The buyout price rises in line with inflation each year effectively capping the costs of the obligation to suppliers and, in turn, consumers. Historical ROC values (2004–2009) were acquired from Ofgem [64–66]. The RO subsidy framework is a tradable mechanism with fluctuating year over year values, therefore difficult methodology choices needed to be made in modeling future ROC values. First the nominal buyout prices needed to be calculated. This required applying the Retail Price Index (RPI) to the previous year's buyout price. Once the nominal prices were obtained for the modeling period, the other variable existing was the probability of the RO being fulfilled. Because the unfulfilled portion of the RO makes up a fund that recycles these funds back to ROC holders, the value of each ROC increases proportionate to the total amount of ROCs redeemed to Ofgem in any given year. The choice was made to derive the arithmetic mean of seven recycle values, ranging from £10.21 to £22.92 per MWh. Certainly this wide range gives a large degree of uncertainty into the probability of future values being above or below this figure. Nevertheless, this methodology choice was made for purposes of brevity, avoidance of untenable speculation into likelihood of the RO being fulfilled, and the system boundary of available research data. It is well acknowledged that this methodology choice may undermine the final results, as the future forecasted level of subsidy support is of paramount importance to underpinning anticipated financial results over life cycle of plant.

Table 1
Synthesized and supplemented operation expenditure estimations.

Source:	Cost per installed MW	Annual percentage cost of CapEx	Cost per MWh of generation	Year
Junginger [62]	*£27 000–£59 400*	2.0–4,4%	*£8.8–£19.36*	2005
DECC (empirical evidence)	*£24 165–£68 310*	1.79%–5.06%	£7.9–£22.30	2005–2008
KPMG [63]	*£80 865*	*5.99%*	£26.40	2007
ODE [44]	*£15 525*	1.15%	*£5.06*	2007
Ernst & Young [51]	€38 000	2.81%	*€12.39*	2007
Risø [4]	*€49 005*	*3.63%*	16€	2008
Ernst & Young [49]	€45 000	*3.33%*	*€14.67*	2009
Douglas Westwood [45]	*£40 500–£67 500*	3–5%	*£15.41–£21.23*	2010

Retail Price Index (RPI) data was collected over a 20-year period from 1990–2009 [67]. These annual changes in RPI are an inflationary indication utilized in the methodology applied by Ofgem when setting the buyout prices (subsidy floor) for each future annual period. Because the RPI changes year over year, a 20-year arithmetic mean was calculated from 1989–2009 to apply towards future ROC floor prices and future LEC values. Consumer price index data was also incorporated for inflationary adjustments. An arithmetic mean of twenty years of CPI data [68] was calculated from the years 1989 to 2009 and applied to operations, maintenance and decommissioning costs in the years post 2010. For the years prior to 2010, the recorded CPI figures were applied in their respective period.

ELEXON's historical 'market index data' was acquired (77 months) for electricity settlement prices in the UK's short-term market [69]. A volume weighted average (VWA) methodology was applied to partially alleviate the distortions load balancing has on overall settlement prices. It was determined that if the settlement price is partially skewed by the amount of volume transacted, this price distortion could be withdrawn from the monthly price trend by applying a VWA to derive market index prices on a monthly basis, fully inclusive of all transactions taking place. The VWA applied also created synonymous denominations of time series to correspond with other data sets that could not be broken down further. More value would be added to this study if output generation was offered on an hourly basis within a diurnal time scale, but output generation data was reported on a monthly basis, which unfortunately offers us no indication of how generation contrasts to intraday load demands. Due to the fact that intraday prices for the sale of power vary based upon consumption load demands, it would be of more inherent financial value to track output generation on an hourly basis to assess if the intermittent nature of these offshore wind resources can positively fulfill the marginal generation demands that occur at peak loads and to what degree of consistency.

The addition of significant amounts of renewable energy as required to meet EU carbon emission reduction targets will ultimately have an impact on future wholesale electricity market prices as well. In terms of running costs, fuel and carbon are the main drivers, but the former are subject to the balance of supply and demand, while the latter depends on the complex mix of regulatory interventions and market fundamentals [54]. This all means that there is huge uncertainty in all future estimates of generation costs, even for the mature thermal generation technologies of combined cycle gas turbines and coal.

Nevertheless future electricity price scenarios needed application to the financial model. Ofgem's Price Discovery project explored whether current market arrangements are capable of delivering secure and sustainable energy supplies, and how these additions of supply will affect future electricity prices. Ofgem constructed a future price scenario analysis based upon the life expectancy of existing supply, future carbon and fuel prices, and the addition of renewables to the portfolio mix within the UK. Their methodology drew upon their depth and knowledge of confidential information available as the utility regulator, yet included a consultation component that allowed feedback and input across all industry wide stakeholders. On the basis of assessing risk and uncertainty in achieving a security of supply within the UK electricity sector, they built a framework against which risks can be assessed and benefits of policy responses can be evaluated. Four primary scenarios were illustrated of how the UK electricity sector will evolve from 2009 to 2025, which reflects the probability and outcomes of meeting environmental objectives under diverging macroeconomic trajectories as displayed in Table 2 and Fig. 5.

Table 2
Ofgem price discovery scenario matrix [70].

		Economic recovery	
		Rapid	Slow
Environmental Action	Rapid	Green transition	Green stimulus
	Slow	Dash for energy	Slow growth

Ofgem estimates that during the impending UK's energy transition, capital investments up to the tune of £200 billion will be needed in the forthcoming 10–15 years to secure new energy supplies and meet carbon targets [70]. It is upmost importance to recognize that across all scenarios, the ease of access to capital markets to meet these colossal capital investment requirements may very well drive the outcome within the sector as a whole. The prices reflected in Figure 5 are applied to the financial appraisal model. Given the uncertainty of future electricity prices, the appropriate means of determining how future energy prices will affect the net present values for the two project sites under investigation is to apply all four projections under a sensitivity analysis. The focus of the scenarios is then not only future wholesale electricity prices, but also how access to capital will change the nature of the investments by virtue of sensitizing the discount rate.

6. Performance metrics

Installed capacity is the most widely disseminated figure regarding new additions to electricity supply. It is the easiest numerical figure for society at large and policy makers lacking a scientific knowledge on the subject to understand and convey. However capacity installed is an inappropriate figure when analyzing the effectiveness of a given energy production technology reliant on natural processes (be it wind, solar, hydro, etc.) as it does not reflect *bona fide* electricity output production. Capacity factor, also referred to as load factor, is noted to be the most accurate indicator and performance metric of output performance for an entire wind farm. Because daily capacity factors vary widely, an accurate and widely accepted representation of capacity factor smooths out temporal variability by measuring on an annual basis. For WTGs, capacity factors are a function of WTG total availability[3], wind regime behavior, and the WTG's power curve relationship with the given wind regime. Capacity factors for entire wind farms also take into account the adverse wake effects upwind WTGs have to the performance of downwind WTGs. Park wide capacity factors also reflect the appropriate micro siting applied, whereas micro siting should be defined as the maximization of capturing wind resource given a specified amount of area. The goal of efficient wind farm operation is to maximize the availability to capture as much of the intermittent resource as technically possible.

Industry trade organizations active in the political lobbying and economic advocacy spheres publish estimated capacity factors for both on and offshore WTG applications. In 2006 the British Wind Energy Association published the anticipated capacity factor of 30% for onshore and 35% for offshore whereas in 2008 they assume that by 2020 capacity factors will reach 44.6% for offshore whereas just months earlier EWEA published the future offshore capacity factor at 40% [71]. It need be duly noted that capacity factors will vary greatly dependent upon geographic location, total availability, and

[3] Total availability is includes maximum time within a year minus scheduled or unscheduled maintenance.

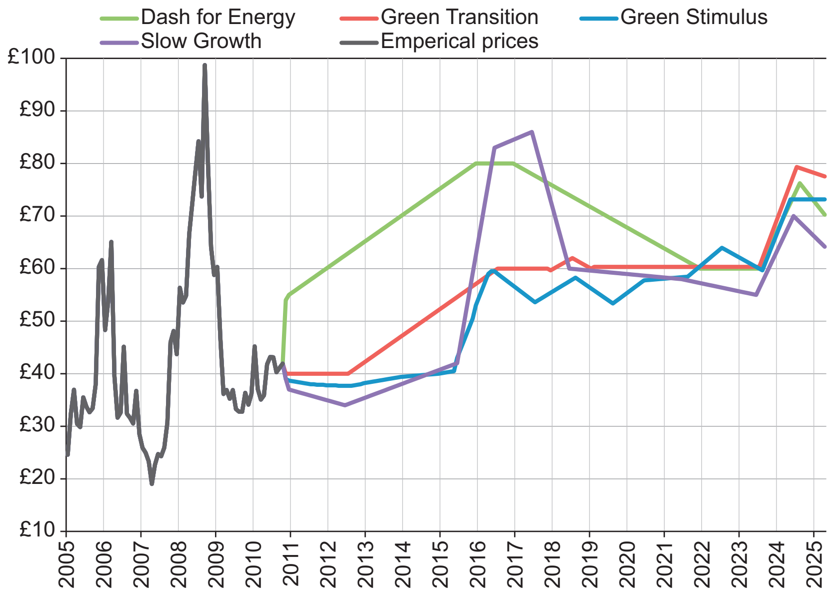

Fig. 5. UK historic wholesale electricity market prices [69] and forecasted scenarios [70].

Table 3
North Hoyle operational performance [47,58–60].

Annual duration	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009
Annual mean wind speed (m/s)	8.7	7.8	8.7	n/a[a]	n/a
Total availability	84%	89,1%	87,4%	n/a	n/a
Production (GWh)	190 752	179 658	184 297	186 690	179 483
Capacity Factor	36.29%	34.18%	35.06%	35.52%	34.15%

[a] Such data is only available for first three years of annual operation through BERR's annual performance reports.

the selected wind turbine generators relationship to the given wind resource (power curve). Therefore caution must be exerted when comparing capacity factors across multiple regions with divergent wind resource behavior patterns [71].

While such generalizations are important to understand the potential and this may suffice for a generalized audience, technical reviewers such as project developers engaged in internalizing the risks associated with deploying offshore wind turbine generators demand more precise evidence in order to make sound investment decisions. Tables 3 and 4 reflect capacity factors achieved for two operational offshore wind farms. Although site specific, such empirical evidence should constitute the basis of fact within future communication on behalf of wind industry trade organizations.

Although a number of technical failures arose in the first three years of operation, it is difficult to see within North Hoyle's operations results displayed in Table 3. In the second operational year, two WTGs suffered extended outages due to generator bearing faults whilst outages on six other WTGs occurred due to faulty gearboxes [58]. Four more WTGs suffered outages from gearbox bearing faults resulting in full gearbox replacements in year three [59]. Npower reported other outages from various technical challenges including rotor cable faults, circuit breaker issues, yaw motor failure and a cracked hub strut. Due to the lack of available information it cannot be confirmed nor denied whether such technical difficulties were an ongoing challenge at North Hoyle after year three. When modeling future performance of the park the performance as achieved within the first five annual periods was replicated for the successive 15 years period. Because generation is recorded at the substation busbar, this choice of future modeling removes untenable speculation with regards to electrical losses, park efficiency (wake losses), or likelihood of recurrence for unplanned outages.

Table 4
Scroby Sands operational performance [50,56,57,60].

Annual duration	2005	2006	2007	2008	2009
Total availability	84.18%	75.1%	83.83%	n/a[a]	n/a
Production (GWh)	152 574	129 053	145 201	155 852	166 184
Capacity factor	29.03%	24.55%	27.63%	29.65%	31.62%

[a] Such data is only available for first three years of annual operation through BERR's annual performance reports.

Scroby Sands operational results in Table 4 reflect that it experienced high levels of technical failures within its first three years of operation. Unplanned works involved larger scale plant problems and as such had more serious implications to the utilization of resources, costs and downtime for E.ON. The primary cause for concern had been the gearbox bearings whereas 27 generator side intermediate speed shaft bearings and 12 high speed shaft bearings had been replaced, in addition to the replacement of four generators, all within the first year [50]. The gearbox problems created a much larger issue and caused reduced levels of availability in the final three months of the year, adversely affecting the performance of the plant as a whole. As such, the total availability dropped to 75.1% for the year. As reliability of crucial components became a key concern, E.ON responded with a substantial amount of planned proactive maintenance activities relating to the issues arising from gearbox bearings and generators. Within the year there were failures on three outboard intermediate speed shaft bearings, nine high-speed shaft bearings and eight generators. The work plan to solve the generator issue at the time was to retrofit each turbine with a generator from a different manufacturer. As a result, Vestas replaced a total of 17 generators. During the autumn and winter of

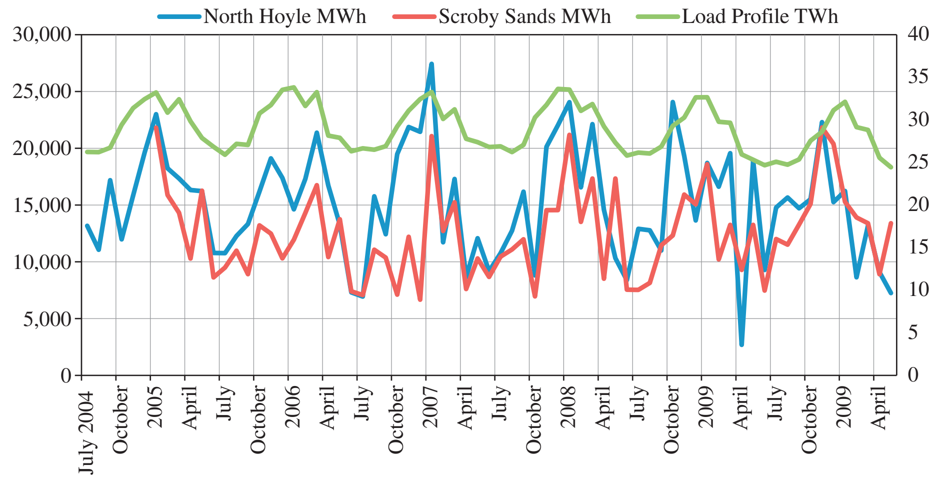

Fig. 6. Monthly project generation and load demand curve [47,50,56–60,72].

Table 5
Financial results for North Hoyle and Scroby Sands under future electricity price scenario sensitivity analyses.

	North Hoyle NPV	North Hoyle IRR	Scroby Sands NPV (£)	Scroby Sands IRR (%)
Green transition	£70 426 665	21.57	£72 975 784	15.29
Green Stimulus	£67 391 806	21.30	£69 513 948	15.05
Dash for Energy	£81 958 749	22.65	£85 044 496	16.17
Slow Growth	£69 548 056	21.44	£71 968 718	15.20

2007, the remaining thirteen original generators were replaced. Lastly, two complete gearboxes were proactively exchanged following the discovery of faults in inboard bearings [56]. Another unplanned issue that arose in year two was when one of the three transition joints[4] buried in the beach failed. The time to remedy was 12 weeks, seriously impacting generation during a high production period.

The technical failures incurred at the Scroby Sand project carried significant consequences on output generation in the first three years of operation. Total availability over this time scale was much lower due to the unplanned work being carried out to remedy the component complications and failures. Production results achieved their highest levels over the empirical time series in 2009 with a total of 166,184 MWh. In modeling future performance, a decision was made to utilize performance as achieved within the first, fourth and fifth production years for all future successive annual periods to the end of the plant's operational life cycle. The decision to exclude years 2 and 3 was made based on the assumption that technical failures incurred during those periods were isolated incidents, had been remedied, and their likelihood of recurrence was fairly low.

Fig. 6 displays a favorable pattern of correlation between monthly output generation at these sites and national load demand. November through February is consistently the strongest period of wind resource and corresponding generation. Load demand for electrical energy is also the strongest during this time. Based upon this information, a case could be made for the ability of offshore wind to be able to meet peak seasonal load demands. A possible implication is the avoidance of marginal cost driven combined cycle natural gas turbines that typically meet this demand. Whist this argument is far reaching and limited, the alignment of production and demand during the winter months is irrefutable. Scroby Sands output production is at its greatest during periods of the most seasonal demand.

[4] These joints connect the submarine export cables to the land export cables.

7. Maximizing value capture: the vertically integrated utility

Both project sites under investigation are owned and operated by vertically integrated energy companies. Both E.ON UK Plc. and Npower Renewables (under the RWE Group) act as both generators and suppliers in the UK market. It is important to attempt to understand how large corporate utilities are maximizing their value capture opportunities through ROCs when both generation and supply are controlled by the same entity. These vertically integrated companies most likely retain and retire their ROCs with Ofgem to meet their RO. It can be said that by foregoing the opportunity to generate an income stream by selling ROCs they produce themselves, more value is created by retaining them and receiving their respective portion of the buyout fund. This in effect also creates an expense mitigation of having to source the marginal ROCs elsewhere. The added costs to a supplier for complying with the RO are ultimately passed on down to the customer, so it can be said that the value of the income stream to these generators (whether incurred directly or through expense mitigation: a zero sum game) are thus the buyout fee plus the recycle value per ROC.

8. Financial results

Under the premise of evaluating investment criterion, envisaging the future is a notoriously hazardous activity. Although these results contain no implicit speculation on behalf of the author, the results presented in this section should be interpreted with special attention to the various data sets available and methodological choices made to derive them. The net present value figures are presented on a pre-tax (EBITDA) basis. A research boundary has been drawn to exclude capital allowances, loss carry forwards or backs, or other such tax treatments. Table 5 presents the net present value (NPV) and internal rate of return (IRR) results derived in this study under the four different future wholesale price scenarios when applying

Table 6
North Hoyle and Scroby Sands discount rate sensitivity analysis results (Million £).

	North Hoyle					Scroby Sands				
	6%	7%	8%	12%	14%	6%	8%	10%	12%	14%
Green transition	124.2	108.3	94.1	51.5	36.3	88.2	59.6	37.6	20.5	7.1
Green stimulus	119.5	104.0	90.3	49.0	34.3	84.3	56.5	35.2	18.7	5.6
Dash for energy	141.6	123.9	108.2	60.9	44.1	101.7	70.3	46.2	27.4	12.6
Slow growth	123.1	107.2	93.1	50.7	35.6	87.1	58.7	36.8	19.9	6.6

each developer's corporate weighted average cost of capital[5] and utilizing ODE's decommissioning cost estimate[6] [44].

North Hoyle's positive financial results can largely be attributed to a few key factors. By capturing the first mover advantage, North Hoyle's project developers were able to acquire two demonstration capital grants to the tune of £12.2 million combined, which effectively reduced their capital exposure by 15%. The wind resource regime at the North Hoyle site produced more robust generation *vis-à-vis* to Scroby Sands.

One striking finding from the scenario results is that although North Hoyle received more capital grants and produced more generation year over year, the Scroby Sands project results in a higher net present value. This can be explained by the fact corporate costs of capital for balance sheet financing was 3% lower for Scroby Sands asset owners.

The sensitivity of NPV to the applied 10% discount rate for North Hoyle and 7% discount rate for Scroby Sands has been performed to reflect how a difference in the cost of capital affects underlying profitability. Sensitized results are presented in Table 6.

Perhaps the most important conclusion one can draw from the aforementioned sensitivity analysis is the extreme importance that cost of capital has to achieving profitability over life cycle of plant in renewable energy projects. In terms of site specific performance, if both projects had the same cost of capital we can clearly see how superior generation and thus financial performance would be with North Hoyle. However because the two sites had different capital financing structures we can see that financial performance was slightly greater for Scoby Sands, despite the fact the robustness of North Hoyle's wind regime was far superior. Whilst its outside the scope of this paper to discuss the myriad factors which constitute pricing within financial markets, the point is simply to illustrate the effect this has by displaying how vastly impacted these projects are by capital financing costs.

9. Conclusions & implications

In assessing project economics, investors will use their own proprietary forward wholesale power, ROC and LEC curves, and their own confidential hurdle rates [51]. Therefore all the aforementioned inputs to the NPV model within this analysis represent only one series of choices of how depict financial appraisal of offshore wind energy projects. Whilst there are limitations when quantifying future profitability in any investment project, the application of the sensitivity analyses within this analysis sought to circumvent most of these limitations. Although the incumbent corporations' revenue and cost streams specific to these energy projects cannot be audited, the results are based upon market behavior observed within the given time scale of the projects in question. Sensitizing key input parameters to the financial model has supported the robustness of the results.

In light of the aforementioned financial appraisal, it can be said that the first two commercial scale offshore wind parks in the UK demonstrate the capacity to produce positive financial returns to their owners over the entire investment horizon. When the decision was made to invest in each project, the high confidence level in several key input parameters must have been substantiated. These key factors were a strong understanding of the wind resource, expectations of high recycle values per ROC, and the presumption that wholesale electricity prices would ultimately rise. The latter two factors would make these investments more profitable later in the investment horizon. Whilst the developers' expectations of financial returns (i.e. hurdle rate) cannot be explicitly stated, it can be deduced that the decision to commit capital to these investments was based upon strong expectations of financial remuneration in addition to corporate strategies of building competence in the undertakings for future activities.

It has been stated that contractors underbid these early projects in order to secure future project activity [40,45], and as a result, several consequences arose. A few contractors engaged in these projects became insolvent (although financial turmoil cannot explicitly be attributed to these projects *per se*). More importantly, the technical issues surrounding successful operation of the WTGs resulted major turbine manufacturers such as Vestas withdrawing their EPC contract offering due to previous failures and the higher risk potential [45]. EPC contract offerings ultimately dried up as the full extent of the offshore construction risks were recognized [40]. It was viewed that such construction activity was outside of core competencies, and bore unnecessary risk upon the organization. However given that higher risks are associated with supplying to offshore projects, there is little incentive for turbine suppliers to provide EPC bids for offshore projects [75]. The high competition for securing such competitive advantages on the procurement and construction side resulted in lower CapEx for project developers.

It can be deduced that the ultimate beneficiaries of these early projects were the developers themselves. By utilizing the EPC contract offering, all risk was shifted upon the contractors. Therefore the project developer was able to secure a lower cost of installation with minimal risk. Certainly cost and risk embody such a relationship that in the instance of capital investments, bearing risk typically bears additional cost. However the contractors for these projects were so interested in securing future project activity by creating a first mover advantage that they were willing to carry these risks and not pass the cost associated with them onto the project developer. This aggressive 'first mover' strategic approach largely benefited the project developer through alleviation of construction risks and removal of risk based pricing in their EPC contracts, much to the latter dismay of some participating contractors.

On the basis of the foregoing analysis it can be seen that these earliest UK offshore farms experienced higher than expected loss of generation within their initial three years of operation, primarily resulting from gearbox and generator failures. One of the

[5] North Hoyle: 10% [73]RWE, "Annual Report 2004," 2005.; Scroby Sands: 7% [74]E.ON, "Group Reports and Accounts for the year ended 31 December 2004," 2005.

[6] £8.25 M nominal (£275, 000 per WTG), inflated to £12,986 M.

most interesting aspects of juxtaposing the two projects is that in terms of component failure, North Hoyle performed mostly as expected whilst reliability at Scroby Sands was riddled with unexpected operational difficulties. In light of the fact that both projects utilized identical WTGs (manufacturer, size, etc.), how can the extensive WTG technical failures experienced at Scroby Sands be explained? It is possible that similar failures occurred in North Hoyle after the third year, and as such, no data reporting is available that offers such information to assess.

Given the pioneering nature of offshore wind energy generation in these formative years, certain operational and technical failures should, to a tolerable degree, be anticipated and expected. Naturally the largest question is: were these failures significant enough to make the ventures unfruitful within their financial results?

The NPV results reflect the fact that although operational performance was temporarily hindered, over the course of the investment cycle both plants were able to provide their corporate owners with adequate levels of financial return. A question that remains unanswered is: what rate of return qualifies as "adequate" or "acceptable" given the inherent levels of risk associated with offshore wind energy projects? Most recently, offshore developers had been claiming that a combination of falling brown power prices and several years of rising capital costs meant that future investments could fail to make hurdle rates of return consistent with offshore risk profiles [12]. Undisclosed hurdle rates may suggest that developers are not willing to send market signals regarding what level of return is required given the corresponding risk level internalized for engaging in such activity. This information would be insightful to understand how capital investors perceive and quantify these risks.

These research results provide support to the notion that developing and operating offshore wind farms possessed the capacity to provide positive net present value results. As the discount rate sensitivity analysis demonstrated, the cost of capital is of paramount importance to derive profit maximization. In a world where investment capital is attracted and garnered through risk based returns, it may seem unlikely that future offshore wind energy projects will be able to attract significant amounts of low-cost capital to reduce its underlying levelized energy costs. Despite this, risk based returns are not the sole investment criterion in today's investment landscape. Increasingly investors have shown interest in allocating their funds in projects that incorporate social and environmental initiatives. At times, some are willing to accept lower returns in consideration for providing a societal good and planetary wellbeing [76].

While such information would be highly fruitful, it is beyond the scope of this report to speculate into how these results correspond to future offshore wind farm projects' profitability. Moreover, attempting to replicate this study from the present day forward hence lacking any site specific empirical evidence (CapEx, OpEx, generation) for any period of time would merely result in a plenary speculative study. With regards to future UK projects, it is difficult to envision a profitable future for the industry given the fact that CapEx has almost tripled over the past 7 years whilst subsidy support has doubled, and capital grants are no longer offered. Compounding the issue, projects are increasingly becoming more complex further from shore in deeper waters. Several examples[7] of weaning developer appetite for pursuing offshore wind indicate current project economics may be unsatisfactory to commit capital.

[7] i.e. Shell's withdrawal from London Array, Fred Olsen Renewables' withdrawal from Forth Array.

While several reports have been published predicting and/or modeling future costs [12,40] to the best of the authors research efforts, none have attempted to apply a similar methodology to derive financial results for individual projects currently under review in the pre-investment phase. It can only be expected that such information does exist and is being tightly safeguarded by actors seeking to protect their commercial interests.

The lack of open information exchange within the nascent offshore wind industry has been cited as causality for its slower than anticipated growth. As far back as 2006, an energy consultant [77] commented that greater interaction and communication was needed throughout the supply chain and that by actively working with contracting suppliers, a project developer's final costs could be reduced. Smit et al. [78] also observed that there was a lack of knowledge sharing in UK and that institutes such as university level research departments did not get access to potentially fruitful project information because offshore wind developers were 'afraid of knowledge leaking away.' This may suggest project developers view open information sharing as a potential loss of competitive advantage. Recently at an offshore wind conference, a project developer [79] advocated for the greater use of open information exchange between developers including more sharing of lessons learnt through failures. The IEA pointed out that [80] unlike the early stages of the offshore oil and gas industry, there is little evidence of information sharing in the offshore wind industry.

The ideology here is simply that knowledge and experience should be viewed as common resources that can benefit the industry as a whole to promote its ensuing growth, rather than be seen as individual competitive tools to be safeguarded under lock and key. Given the rise of consortiums to tackle larger offshore wind parks within Round 3, the multi-stakeholder participation framework might facilitate knowledge exchange and expertise existing within varying industry participants, thus benefitting the industry as a whole.

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